

# MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

**Permitting and Compliance Division  
1520 E. Sixth Avenue  
P.O. Box 200901  
Helena, Montana 59620-0901**

CHS, Inc.  
Laurel Refinery  
802 South Highway 212  
P.O. Box 909  
Laurel, Montana 59044-0909

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

Facility Compliance Requirements	Yes	No	Comments
Source Tests Required	X		Methods 5/5B/5F (PM) Methods 6/6C (SO <sub>2</sub> ) Method 7 (NO <sub>x</sub> ) Method 9 (opacity) Method 10 (CO) Method 11 (H <sub>2</sub> S) Method 18 (VOC)
Ambient Monitoring Required		X	
COMS Required	X		FCC Regenerator
CEMS Required	X		SO <sub>2</sub> , H <sub>2</sub> S, NO <sub>x</sub> , CO
Schedule of Compliance Required		X	
Annual Compliance Certification and Semiannual Reporting Required	X		
Monthly Reporting Required		X	
Quarterly Reporting Required	X		
<b>Applicable Air Quality Programs</b>			
ARM Subchapter 7 Montana Air Quality Permits (MAQP)	X		MAQP #1821-28
New Source Performance Standards (NSPS)	X		40 CFR 60, Subpart A, Subpart J, Subpart Ja, Subpart Db, Subpart Kb, Subpart UU, Subpart VV (as required by MACT CC), Subpart VVa, Subpart GGG, Subpart GGGa, Subpart QQQ
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	X		40 CFR 61, Subpart A, Subpart FF
Maximum Achievable Control Technology (MACT)	X		40 CFR 63, Subpart A, Subpart R (as required by Subpart CC), Subpart CC, Subpart UUU, Subpart ZZZZ
Major New Source Review (NSR) – includes Prevention of Significant Deterioration (PSD) and/or Non-attainment Area (NAA) NSR	X		
Risk Management Plan Required (RMP)	X		
Acid Rain Title IV		X	
Compliance Assurance Monitoring (CAM)		X	
State Implementation Plan (SIP)	X		Billings/Laurel SO <sub>2</sub> Control Plan

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## SECTION I. GENERAL INFORMATION

### A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emission units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the U.S. Environmental Protection Agency (EPA) and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit.

Conclusions in this document are based on information provided in the original application submitted to the Montana Department of Environmental Quality Air Resources Management Bureau (Department) by Cenex Harvest States Cooperatives (Cenex) on 07/10/95, the application for renewal submitted by CHS, Inc. (CHS) on May 12, 2006, and the significant modification applications submitted by CHS on October 10, 2007; February 25, 2008; November 7, 2008; February 27, 2009; August 13, 2009; September 17, 2009; March 31, 2010 (determined to be substantively and technically complete on April 22, 2010); July 27, 2010; November 1, 2010; April 12, 2011; November 8, 2011; June 4, 2012 (determined to be administratively complete on July 25, 2012 and technically complete on October 4, 2012).

### B. Facility Location

The CHS-Laurel Refinery is located at the South ½, Section 16, Township 2 South, Range 24 East, Yellowstone County. This legal description refers to a physical address of 802 South Highway 212, Laurel, Montana.

### C. Facility Background Information

#### Montana Air Quality Permit History

On May 11, 1992, Cenex was issued **Montana Air Quality Permit (MAQP) #1821-01** for the construction and operation of a hydro-treating process to desulfurize Fluidized Catalytic Cracking Unit (FCCU) feedstocks. The existing refinery property lies immediately south of the City of Laurel and about 13 miles southwest of Billings, Montana. The new equipment for the desulfurization complex is located near the western boundary of the existing refining facilities.

The Hydrodesulfurization (HDS) process is utilized to pretreat FCCU feeds by removing metal, nitrogen, and sulfur compounds from these feeds. The proposed HDS unit also improved the quality of refinery finished products including gasoline, kerosene, and diesel fuel. The HDS project significantly improved the finished product quality by reducing the overall sulfur contents of liquid products from the Cenex Refinery. The HDS unit provided low sulfur gas-oil feedstocks for the FCCU, which resulted in major reductions of sulfur oxide emissions to the atmosphere. However, only a minor quantity of the proposed sulfur dioxide (SO<sub>2</sub>) emission reductions were made federally enforceable.

The application was not subject to the New Source Review (NSR) program for either nonattainment or Prevention of Significant Deterioration (PSD) since Cenex chose to "net out of major modification review" for the affected pollutants due to contemporaneous emission reductions at an existing emission unit.

The application was deemed complete on March 24, 1992. Additional information was received on April 16, 1992, in which Cenex proposed new short-term emission rates based upon modeled air quality impacts.

The basis for the permit application was due to a net contemporaneous emission increase that was less than the significant level of 40 tons per year for SO<sub>2</sub> and oxides of nitrogen (NO<sub>x</sub>). The application referred to significant SO<sub>2</sub> emission reductions that were expected by addition of the HDS project. These anticipated major SO<sub>2</sub> reductions were not committed to by Cenex under federally enforceable permit conditions and limitations. The contemporaneous emission decreases for SO<sub>2</sub> and NO<sub>x</sub>, which were made federally enforceable under this permitting action, amount to approximately 15.5 and 23.7 tons per year, respectively. Construction of the HDS/sulfur recovery complex was completed in December 1993, and the 180-day shakedown period ended in June 1994.

**MAQP #1821-02** was issued on February 1, 1997, to authorize the installation of an additional boiler (#10 Boiler) to provide steam for the facility. Cenex submitted the original permit application for a 182.50-million British thermal unit per hour (MMBtu/hr) boiler on February 9, 1996. This size boiler is a New Source Performance Standard (NSPS)-affected facility and the requirements of NSPS, Subpart Db, would have applied to the boiler. On November 15, 1996, Cenex submitted a revised permit application proposing a smaller boiler (99.90 MMBtu/hr). The manufacturer of the proposed boiler had not been identified; however, the boiler was to be rated at approximately 80,000 pounds (lbs) steam/hour with a heat input of 99.9 MMBtu/hour. The boiler shall have a minimum stack height of 75 feet above ground level. The boiler will be fired on natural gas until November 1, 1997, at which time Cenex will be allowed to fire refinery fuel gas in the boiler. The requirements of NSPS, Subpart Dc, apply to the boiler. The requirements of NSPS, Subpart J and GGG, also applied as of November 1, 1997. Increases in emissions from the new boiler were detailed in Section IV of the permit analysis for MAQP #1821-02. Modeling performed showed that the emissions increase would not result in a significant impact to the ambient air quality (see Section VI of the permit analysis).

Cenex also requested a permit alteration to remove the SO<sub>2</sub> emission limits (Section II.E.2.a of MAQP #1821-01) for the C-201B compressor engine because the permit already limits C-201B to be fired on either natural gas or unodorized propane. Cenex also requested that if the SO<sub>2</sub> emission limits could not be removed, the limits should be corrected to allow for the combustion of natural gas and propane. The Department altered the permit to allow for burning odorized propane in the C-201B compressor.

Cenex also requested a permit modification to change the method of determining compliance with the HDS Complex emitting units. MAQP #1821-01 required that compliance with the hourly (lb/hr) emission limits be determined through annual source testing and that the daily (lb/day), annual (ton/yr), and Administrative Rules of Montana (ARM) 17.8, Subchapter 8, requirements (i.e., PSD significant levels and review) be determined by using actual fuel-burning rates and the manufacturer's guaranteed emission factors listed in Attachment B. Cenex requested to use actual fuel-burning rates and fixed emission factors determined from previous source test data in order to determine compliance with the daily (lb/day) and annual (ton/yr) emission limits. The Department agreed that actual stack testing data is preferred to manufacturer's data for the development of emission factors. However, the Department required that the emission factor be developed from the most recent source test and not on an average of previous source tests. The permit was changed to remove Attachment B and rely on emission factors derived from the most recent source test, along with actual fuel flow rates for compliance determinations. However, in order to determine compliance with ARM 17.8, Subchapter 8, Cenex shall continue to monitor the fuel gas flow rates in both scf/hr and scf/year.

This permit (#1821-02) was written to maintain the language from the HDS Complex MAQP #1821-01, where possible, and to separate the HDS Complex MAQP #1821-01 requirements from the requirements for the current action (Boiler #10). The permit requirements from MAQP #1821-01 were included in MAQP #1821-02.

On June 4, 1997, Cenex was issued **MAQP #1821-03** to modify emissions and operational limitations on components in the HDS Complex at the Laurel refinery. The unit was originally permitted in 1992, but has not been able to operate adequately under the emission and operational limitations originally proposed

by Cenex and permitted by the Department. This permitting action corrected these limitations and conditions. The new limitations established by this permitting action were based on operational experience and source testing at the facility and the application of Best Available Control Technology (BACT). The following emission limitations were modified by this permit.

Source	Pollutant	Previous Limit	New Limit
SRU Incinerator stack (E-407 & INC-401)	SO <sub>2</sub>	291.36 lb/day	341.04 lb/day
	NO <sub>x</sub>	2.1 ton/yr 11.52 lb/day 0.48 lb/hr	3.5 ton/yr 19.2 lb/day 0.8 lb/hr
Compressor (C201-B)	NO <sub>x</sub>	18.42 ton/yr	30.42 ton/yr
		6.26 lb/hr	7.14 lb/hr
	CO	16.45 ton/yr	68.6 ton/yr
		5.15 lb/hr - when on natural gas	6.4 lb/hr - when on natural gas
	VOC	6.26 ton/yr	10.1 ton/yr
Fractionator Feed Heater (H-202)	SO <sub>2</sub>	0.53 ton/yr	4.93 ton/yr
		0.135 lb/hr	1.24 lb/hr
	NO <sub>x</sub>	6.26 ton/yr	8.34 ton/yr
		1.43 lb/hr	2.09 lb/hr
	CO	3.29 ton/yr	6.42 ton/yr
		1.00 lb/hr	1.61 lb/hr
	VOC	0.26 ton/yr	0.51 ton/yr
Reactor Charge Heater (H-201)	SO <sub>2</sub>	0.214 lb/hr	1.716 lb/hr
		0.79 ton/yr	6.83 ton/yr
	NO <sub>x</sub>	9.24 ton/yr	11.56 ton/yr
		2.11 lb/hr	2.90 lb/hr
H-201 (cont.)	CO	4.86 ton/yr	8.89 ton/yr
		1.40 lb/hr	2.23 lbs/hr
	VOC	0.39 ton/yr	0.71 ton/yr
Reformer Heater (H-101)	SO <sub>2</sub>	0.128 lb/hr	2.15 lb/hr
		0.48 ton/yr	3.35 ton/yr
	NO <sub>x</sub>	6.16 lb/hr	6.78 lb/hr
	VOC	0.24 ton/yr	0.35 ton/yr
Old Sour Water Stripper	SO <sub>2</sub>	304.2 ton/yr	290.9 ton/yr
	NO <sub>x</sub>	125.7 ton/yr	107.9 ton/yr

Emission limitations in this permit are based on the revised heat input capacities for units within the HDS. The following changes were made to the operational requirements of the facility.

Unit	Originally Permitted Capacity	New Capacity
SRU Incinerator stack (E-407 & INC-401)	4.8 MMBtu/hr	8.05 MMBtu/hr
Compressor (C201-B)	1600 HP (short term) 1067 HP (annual average)	1800 HP (short term and annual average)
Fractionator Feed Heater (H-202)	27.2 MMBtu/hr (short term) 20.4 MMBtu/hr (annual avg.)	29.9 MMBtu/hr (short term) 27.2 MMBtu/hr (annual avg.)
Reactor Charge Heater (H-201)	37.7 MMBtu/hr (short term) 30.2 MMBtu/hr (annual avg.)	41.5 MMBtu/hr (short term) 37.7 MMBtu/hr (annual avg.)
Reformer Heater (H-101)	123.2 MMBtu/hr (short term and annual avg.)	135.5 MMBtu/hr (short term) 123.2 MMBtu/hr (annual avg.)

It was determined that the emission and operational rates proposed during the original permitting of the HDS unit were incorrect and should have been at the levels Cenex was now proposing. Because of this, the permit action and the original permitting of the HDS had to be considered one project in order to determine the permitting requirements. When combined with the original permitting of the HDS, the emission increases of NO<sub>x</sub> and SO<sub>2</sub> would exceed significant levels and subject this action to the requirements of the NSR/PSD program. During the original permitting of the HDS complex, Cenex chose to “net out” of NSR and PSD review by accepting limitations on the emissions of NO<sub>x</sub> and SO<sub>2</sub> from the old sour water stripper (SWS). Because of the emission increases proposed in this permitting action, additional emission reductions had to occur. Cenex proposed additional reductions in emissions from the old SWS to offset the increases allowed by this permitting action. These limitations would reduce the “net emissions increase” to less than significant levels and negate the need for review under the NSR/PSD program. The new emission limits for SO<sub>2</sub> and NO<sub>x</sub> from the old SWS are 290.9 and 107.9 tons/year, respectively.

This permitting action also removed the emission limits and testing requirements for particulate matter less than 10 microns (PM<sub>10</sub>) on the HDS Heaters (H-101, H-201, and H-202). These heaters combust refinery gas, natural gas and PSA gas. The Department determined that potential PM<sub>10</sub> emissions from these fuels were minor and that emission limits and the subsequent compliance demonstrations for this pollutant were unnecessary. Also removed from this permit were the compliance demonstration requirements for SO<sub>2</sub> and volatile organic compounds (VOCs) when the combustion units are firing natural gas. The Department determined that firing the units solely on natural gas would, in itself, demonstrate compliance with the applicable limits.

This action would result in an increase in allowable emissions of VOC and carbon monoxide (CO) by 4.7 ton/yr and 60 ton/yr, respectively. Because of the offsets provided by reducing emissions from the old SWS, this permitting action would not increase allowable emissions of SO<sub>2</sub> or NO<sub>x</sub> from the facility.

The following changes were made to the Department’s preliminary determination (PD) in response to comments from Cenex.

1. The emission limits for the old SWS in Section II.D.2 were revised to ensure that the required offsets were provided without putting Cenex in a non-compliance situation at issuance of the permit. The compliance determinations of Section II.G.5 and the reporting requirements of Section II.H.1.d were also changed to reflect this requirement.

2. The CO emission limits for H-201 in Section II.D.6 were revised; the old limits were inadvertently left in the PD. The table in Section I.B of the analysis was also changed to reflect this.
3. Section III.E.2 was changed to clarify that the firing of natural gas would show compliance with the VOC emission limits for Boiler #10.
4. Section F of the General Conditions was removed because the Department had placed the applicable requirements from the permit application into the permit.
5. Numbering had been changed in Section III.

**MAQP #1821-04** was issued to Cenex on March 6, 1998, in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC - National Emission Standards for Petroleum Refineries, by August 18, 1998. Cenex proposed to install a gasoline vapor collection system and enclosed flare for the reduction of hazardous air pollutants (HAPs) resulting from the loading of gasoline. A vapor combustion unit (VCU) was added to the product loading rack. The gasoline vapors would be collected from the trucks during loading, then routed to an enclosed flare where combustion would occur. The result of this project would be an overall reduction in the amount of VOCs (503.7 tons per year (tpy)) and HAPs emitted, but CO and NO<sub>x</sub> emissions would increase slightly (4.54 tpy and 1.82 tpy).

The product loading rack was used to transfer refinery products (gasoline, burner and/or diesel fuels) from tank storage to trucks, which transport gasoline and other products, to retail outlets. The loading rack consisted of three arms, each with a capacity of 500 gallons per minute (gpm). However, only two loading arms were presently used for loading gasoline at any one time. A maximum gasoline-loading rate of 2000 gpm, a maximum short-term rate, was modeled to account for future expansion.

Because Cenex's product loading rack VCU was defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, a determination that the emissions from the VCU would constitute a negligible risk to public health was required prior to the issuance of a permit to the facility. Cenex and the Department identified the following hazardous air pollutants from the flare, which were used in the health risk assessment. These constituents are typical components of Cenex's gasoline.

1. Benzene
2. Toluene
3. Ethyl Benzene
4. Xylenes
5. Hexane
6. 2,2,4 Trimethylpentane
7. Cumene
8. Naphthalene
9. Biphenyl

The reference concentration for Benzene was obtained from EPA's Integrated Risk Information System (IRIS) database. The ISCT3 modeling performed by Cenex, for the hazardous air pollutants identified above, demonstrated compliance with the negligible risk requirement.

On September 3, 2000, **MAQP #1821-05** was issued to Cenex to revamp its No. 1 Crude Unit in order to increase crude capacity, improve product quality, and enhance energy recovery. The proposed project involved the replacement and upgrade of various heat exchangers, pumps, valves, towers, and other equipment. Only VOC emissions would be affected by the proposed new equipment. The capacity of the No. 1 Crude Unit was expected to increase by 10,000 or more barrels per stream day.

No increase in allowable emissions was sought under this permit application. The proposed project actually decreased VOC emissions from the No. 1 Crude Unit. However, increasing the capacity of the No. 1 Crude Unit was expected to increase the current utilization of other units throughout the refinery and thus may increase actual site-wide emissions, as compared to previous historical levels. Therefore, the permit included enforceable limits, requested by Cenex, on future site-wide emissions. The limits allowed emission increases to remain below the applicable significant modification thresholds that trigger the NSR program for PSD and Nonattainment Area (NAA) permitting.

The site-wide limits were calculated based on the addition of the PSD/NAA significance level for each particular pollutant to the actual refinery emissions from April 1998, through March 2000, for SO<sub>2</sub>, NO<sub>x</sub>, CO, PM<sub>10</sub>, and total suspended particulate (TSP) minus 0.1 tpy, to remain below the significance level. A similar methodology was used for the VOC emissions cap, except that baseline data from the time period 1993 and 1999 were used to track creditable increases and decreases in emissions. The site-wide limits are listed in the following table.

Pollutant	Period Considered for Prior Actual Emissions	Average Emissions over 2-yr Period (tpy)	PSD/NAA Significance Level (tpy)	Proposed Emissions Cap (tpy)
SO <sub>2</sub>	April 1998-March 2000	2940.4	40	2980.3
NO <sub>x</sub>	April 1998-March 2000	959.5	40	999.4
CO	April 1998-March 2000	430.8	100	530.7
VOC	1993-1999	1927.6	40	1967.5
PM-10	April 1998-March 2000	137.3	15	152.2
TSP	April 1998-March 2000	137.3	25	162.2

For example, the SO<sub>2</sub> annual emissions cap was calculated as follows:

Average refinery-wide SO<sub>2</sub> emissions in the period of April 1998 through 2000, added to the PSD/NAA significance level for SO<sub>2</sub> minus 0.1 tpy =

$$2940.4 \text{ tpy} + 40 \text{ tpy} - 0.1 \text{ tpy} = 2980.3 \text{ tpy} = \text{Annual emissions cap.}$$

MAQP #1821-05 replaced MAQP #1821-04. This was the last permitting action for the initial Title V Operating Permit #OP1821-00.

**MAQP #1821-06** was issued on April 26, 2001, for the installation and operation of eight temporary, portable Genertek reciprocating engine electricity generators and two accompanying distillate fuel storage tanks. Each generator is capable of generating approximately 2.5 megawatts of power. These generators are necessary because of the high cost of electricity. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Cenex to acquire a more economical supply of power.

Because these generators would only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualifies as a “temporary source” under the PSD permitting program because the permit will limit the operation of these generators to a time period of less than 2 years. Therefore, Cenex would not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 would be ensured. In addition, Cenex would be responsible for complying with all applicable air quality standards. In order to keep this permitting action below the threshold of nonattainment area permitting requirements, Cenex requested a limitation to keep the project’s potential emissions of SO<sub>2</sub> below 40 tons. MAQP #1821-06 replaced MAQP #1821-05.

**MAQP #1821-07** was issued on August 28, 2001, to change the wording in Section VII.A.2, regarding the stack height on the temporary generators, to allow for the installation of mufflers on those stacks, thus increasing the total stack height. In addition, the Department modified the permit to eliminate references to the repealed odor rule (ARM 17.8.315), to correct conditions improperly referencing the incinerator rule (ARM 17.8.316), and to update a testing frequency on the product loading rack VCU based on the Title V permit term. **MAQP #1821-07** replaced **MAQP #1821-06**.

On June 3, 2002, the Department received a request from Cenex to modify **MAQP #1821-07** to remove all references to 8 temporary, portable electricity generators. The generators were permitted under **MAQP #1821-06**, with further clarification added in **MAQP #1821-07** regarding generator stack height. The generators have not been operated since August 10, 2001, and Cenex has no intention of operating them in the future. The references to the generators were removed, and the generators are no longer included in Cenex's permitted equipment. **MAQP #1821-08** replaced **MAQP #1821-07**.

On March 13, 2003, the Department received a complete **MAQP** Application from Cenex to modify **MAQP #1821-08** to add a new Ultra Low Sulfur Diesel (ULSD) Unit, Hydrogen Plant, and associated equipment to meet the EPA's 15 parts per million (ppm) sulfur standard for highway diesel fuel for 2006. The permit action removed the Middle Distillate Unifiner (MDU) charge heater, MDU stripper heater, MDU fugitives, and the #3 and #4 Unifier Compressors. The ULSD Unit included two heaters, four compressors, C-901 A/B and C-902 A/B, process drains, and fugitive piping components. The Hydrogen Plant included a single fired reformer heater, process drains, and fugitive piping components.

The treated stream from the ULSD Unit was separated into its constituent fuel blending products or into material needing further refining. The resulting stream was then stored in existing tanks and one new tank (128). Three existing tanks (73, 86, and 117) were converted to natural gas blanketed tanks to reduce emissions of VOCs from the ULSD Unit feed stock product streams. Cenex was to install a new Tail Gas Treatment Unit (TGTU) for both the Sulfur Recovery Unit (SRU) #1 and #2 trains that will be operational prior to startup of the ULSD Unit but technically are not part of this permitting action. **MAQP #1821-09** replaced **MAQP #1821-08**.

On July 30, 2003, the Department received a complete **MAQP** Application from CHS to modify **MAQP #1821-09**. The application was complete with the addition of modeling information provided to the Department on August 22, 2003. CHS requested to add a new TGTU and associated equipment for Zone A's SRU #1 and SRU #2 trains to control and reduce SO<sub>2</sub> emissions from this source. CHS submitted modeling to the Department for a determination of a minimum stack height for the existing SRU #1 and SRU #2 tail gas incinerator stack. CHS also submitted a letter to the Department to change the name on the permit from Cenex to CHS. The permit action added the new TGTU, set a minimum stack height for the tail gas incinerator stack, and changed the name on the permit from Cenex to CHS. **MAQP #1821-10** replaced **MAQP #1821-09**.

On June 1, 2004, the Department received two **MAQP** Applications from CHS to modify **MAQP #1821-10**. The applications were complete with the addition of requested information provided to the Department on June 16, 2004. In one application CHS requested to change the nomenclature for Reformer Heater H-801 to Reformer Heater H-1001. H-801 was previously permitted during the ULSD project (**MAQP #1821-09**), at 150-MMBtu/hr. CHS requested to change the size of Reformer Heater H-801 (H-1001) from 150-MMBtu/hr to 161.56-MMBtu/hr. In the other application CHS requested to increase the Plantwide Applicability Limit (PAL) for CO from 530.7 tons per year to 678.2 tons per year based on new information obtained by CHS. The new information was obtained after the installation of a CO continuous emission monitor (CEMS) on the FCCU Stack. Emissions of CO from the FCCU Stack were assumed to be zero until the installation of the CEMS. CHS also requested that specific emission limits, standards, and schedules required by the CHS Consent Decree be incorporated into the permit. **MAQP #1821-11** replaced **MAQP #1821-10**.

On December 15, 2004, the Department received a letter from CHS to amend MAQP #1821-11. The changes were administrative primarily related to changing routine reporting requirements from a monthly basis to quarterly. The changes to the permit were made under the provisions of ARM 17.8.764, Administrative Amendment to Permit. **MAQP #1821-12** replaced MAQP #1821-11.

On March 28, 2006, the Department issued **MAQP #1821-13** to CHS to build a new 15,000-barrel per day (BPD) delayed coker unit and associated equipment. The new delayed coker unit allows CHS to increase gasoline and diesel production by 10-15% by processing heavy streams that formerly resulted in asphalt (asphalt production is expected to decrease by approximately 75%, but the capability to produce asphalt at current levels was maintained and no emission credits were taken with respect to any possible reduction in asphalt production) without increasing overall crude capacity at the refinery. The delayed coker unit produces 800 short tons per day of a solid petroleum coke product. To accommodate the downstream changes created by the new delayed coker unit, several other units will be modified including the Zone D FCC Feed Hydrotreater, FCCU, ULSD Unit, and Hydrofluoric Acid (HF) Alky Unit. Other units will be added: Delayed Coker SRU/TGTU/Tail Gas Incinerator (TGI), Naphtha Hydrotreating (NHT) Unit, NHT Charge Heater, Boiler No. 11, Light Products Railcar Loading Facility, and two new tanks will be added to the Tank Farm. Other units will be shut down: the Propane Deasphalting Unit, Unifiner Compressors No. 1 and 2, No. 2 Naphtha Unifier Charge Heater and Reboiler, BP2 Pitch Heater, and Boilers No. 3 and 4. The VCU associated with the new Light Products Railcar Loading Facility and the Coker Unit TGI were subject to the requirements of 75-2-215, MCA and ARM 17.8.770, Additional Requirements for Incinerators. The Delayed Coker project and associated equipment modifications did not cause a net emission increase greater than significant levels and, therefore, does not require a NSR analysis. The net emission changes were as follows:

Constituent	Total Project PTE (ton/yr)	Contemporaneous Emission Changes (ton/yr)	Net Emissions Change (ton/yr)	PSD Significance Level (ton/yr)
NO <sub>x</sub>	39.2	-7.5	31.8	40
VOC	-1.5	-53.3	-54.8	40
CO	106.7	-23.2	83.5	100
SO <sub>2</sub>	39.7	0.0	39.7	40
PM	7.6	6.6	14.2	25
PM <sub>10</sub>	6.7	6.6	13.3	15

The following is a summary of the CO emissions included in the CO netting analysis: Coker project (+106.7 TPY), emergency generator (+0.44 TPY, start-up in 2002), Zone A TGTU project (+8.3 TPY, initial startup at end of 2004), and ULSD project (-31.9 TPY, started up in 2005). MAQP #1821-13 replaced MAQP #1821-12.

On May 4, 2006, the Department received a complete application from CHS to incorporate the final design of three emission sources associated with the new 15,000 BPD delayed coker unit project permitted under MAQP #1821-13. The final design capacities have increased for the new NHT Charge Heater, the new Coker Charge Heater and the new Boiler No. 11. The application also includes a request to reduce the refinery-wide fuel oil burning SO<sub>2</sub> emission limitation. This reduction allows CHS to stay below the significance threshold for the applicability of the New Source Review-PSD program. The maximum firing rates are proposed to increase with the current permitting action. The following summarizes the originally permitted firing rates (MAQP #1821-13) and the new proposed firing rates for the heaters and the boiler:

NHT Charge Heater: 13.2 to 20.1 MMBtu-lower heating value (LHV)/hr (22.1 MMBtu-higher heating value (HHV)/hr)

Coker Charge Heater: 129.3 to 146.2 MMBtu-LHV/hr (160.9 MMBtu-HHV/hr)

Boiler #11: 175.9 to 190.1 MMBtu-LHV/hr (209.1 MMBtu-HHV/hr)

CHS also requested several clarifications to the permit. Under MAQP #1821-13 several 12-month rolling limits were established for modified older equipment and limits for new equipment. CHS requested clarifications be included to determine when compliance would need to be demonstrated for these new limits. MAQP #1821-13 went final on March 28, 2006, and CHS is required to demonstrate compliance with the new limitations from this date forward. For the 12-month rolling limits proposed under MAQP #1821-13 and any changes to limitations under the current permit action, CHS would be required to demonstrate compliance on a monthly rolling basis calculated from March 28, 2006. For modified units the limitations will have zero emissions until modifications are made. New units will have zero emissions until start-up of these units. Start-up is defined as the time that the unit is combusting fuel, not after the start-up demonstration period. Some units have clearly designated compliance timeframes based on the consent decree. These limitations and associated time periods are listed within the permit.

The Department agreed that the heading to Section X.A.3 can include the “*Naphtha Hydrotreating Unit*”; Section D.1.c is based on a 30-day rolling average; Section X.D.7.a.ii should state that the SO<sub>2</sub> limit is based on a 12-hour average; and that Section XI.E.3 should be revised to remove the requirement for a stack gas volumetric flow rate monitor. The Department made some clarifications to the language in Section X.D.6.b. The Department’s intent in permitting the coke pile with enclosures was to ensure that at no time would the coke pile be higher than the top of the enclosure walls at any point on the pile, not only the portion of the pile that is adjacent to the wall.

The Department did not believe it was necessary to designate the Sour Water Storage Tank as a 40 CFR 60 Subpart Kb applicable tank, when currently these regulations do not apply. If CHS makes changes in the future and 40 CFR 60 Subpart Kb becomes applicable to the tank, then CHS can notify the Department and the Department can include the change in the next permit action.

The Department received comments from CHS on the preliminary determination of **MAQP #1821-14** on June 21, 2006. The comments were editorial in nature and the changes were made prior to issuance of the Department Determination on MAQP #1821-14. CHS requested corrections to the PM, PM<sub>10</sub>, NO<sub>x</sub> netting values in Section II.G of the permit analysis, and the Department agreed that the edits were needed. CHS also requested further clarification to the requirements of Section X.D.6.b of the permit.

CHS stated that the coke pile will be dropped from two coke drums to a location directly adjacent to the highest walls of the enclosure area. The height of the dropped coke piles will not exceed the height of the wall. If CHS is required to relocate and temporarily store the coke at another location within the enclosure area, CHS will not pile the coke higher than the walls adjacent to the temporary storage location. MAQP #1821-14 replaced MAQP #1821-13.

On September 11, 2006, the Department received an application from CHS to incorporate the final design of emission sources associated with the new 15,000-BPD delayed coker unit project permitted under MAQP #1821-13 and revised under MAQP #1821-14. The changes include:

- Retaining Boiler #4 operations and permanently shutting down the CO Boiler;
- Modifying the FCCU Regenerator CO limit due to the air grid replacement;
- Rescinding the permitted debottleneck project for Zone D SRU/TGTU/TGI and revising the long term SO<sub>2</sub> potential to emit;
- Modifying the Zone E (Delayed Coker) SRU/TGTU/TGI - Incinerator design and NO<sub>x</sub> limits;
- Rescinding the firing rate restriction and associated long-term emission limits, and revising VOC emission calculations for H-201 and H-202; and
- Removing the 99.9 MMBtu/hr restriction and reclassifying Boiler #10 as subject to NSPS Subpart Db.

On October 11, 2006, the Department received a request to temporarily stop review of the permit application until several additional proposals were submitted, which included:

- On October 24, 2006, the Department received a de minimis notification for stack design changes for the Delayed Coker Unit (Zone E) SRU Incinerator.
- On October 31, 2006, the Department received clarification on the ULSD project.
- On November 1, 2006, the Department received a request to limit the maximum heat rate capacity of the #2 N.U. Heater to below 40 MM BTU/hr in conformance with the CHS Consent Decree. CHS also requested that the Department re-initiate review of MAQP Modification #1821-15.

All of the above changes allowed CHS to stay below the significance threshold for the applicability of the New Source Review-PSD program. CHS also requested several clarifications to be included in the permit, and the Department suggested streamlining the permit's organization. **MAQP #1821-15** replaced MAQP #1821-14.

On October 10, 2007, the Department received an application from CHS to modify MAQP #1821-15 to incorporate the final design of the NHT Charge Heater. This heater was permitted as part of the refinery's delayed coker project permitted under MAQP #1821-13 and revised under MAQP #1821-14 and MAQP #1821-15. The modification to MAQP #1821-15 was requested to address an operating scenario that was overlooked during the delayed coker unit design process. This operating scenario is for the case in which the NHT unit is in operation, but the delayed coker unit is not. In this operating scenario, the characteristics of the naphtha being processed in the unit are such that additional heat input to the heater is required to achieve the design NHT Unit throughput. For this reason, CHS requested approval for an increase in the design firing rate of the NHT Charge Heater (H-8301). The following summarizes the permitted firing rates under MAQP #1821-15 and the new proposed firing rates for the NHT Charge Heater:

Maximum Firing Rate (LHV): 20.1 MMBtu-LHV/hr to 34.0 MMBtu-LHV/hr  
Maximum Firing Rate (HHV): 22.1 MMBtu-HHV/hr to 37.4 MMBtu-HHV/hr

This change does not impact any of the other design conditions in the original delayed coker permit, including unit throughputs and operating rates. The application also includes a request to reduce the refinery-wide fuel oil burning SO<sub>2</sub> emission limitation. This reduction allows CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program. CHS also requested some administrative changes to the permit. **MAQP #1821-16** replaced MAQP #1821-15.

On February 25, 2008, the Department received a complete application from CHS to modify MAQP #1821-16 for the completion of two separate projects. For the first project, CHS proposed to construct a new 209.1 MMBtu-HHV/hr steam generating boiler (Boiler #12). This project includes the permanent shutdown of two existing boilers, Boilers #4 and #5, which have a combined capacity of 190 MMBtu-LHV/hr. The two existing boilers are being shutdown in part to meet the consent decree NO<sub>x</sub> reduction requirements, as well as to generate NO<sub>x</sub> offsets for this permitting action.<sup>1</sup> Due to the operational complexity of replacing two existing boilers with one new boiler in the refinery steam system, CHS requested to maintain the ability to operate the #5 Boiler for 1 year after initial start-up of Boiler #12. Combustion of fuel oil in the refinery boilers would also be eliminated primarily to generate NO<sub>x</sub> offsets for this permitting action.

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<sup>1</sup> This is later clarified in the permit history for MAQP #1821-21. No creditable NO<sub>x</sub> emissions reductions from the shutdown of Boiler #4 and #5 were used in the permit for construction of new Boiler #12 (MAQP #1821-17).

For the second project, CHS proposed an expansion of its railcar light product loading facilities. Although there would be no increase in refinery production from this expansion, the project would increase flexibility in the transportation of refinery products. After project completion, there would be a total of nine spots available at this loading rack for product loading into railcars. The railcar light product loading facility was originally permitted as part of the delayed coker project permitted under MAQP #1821-13 and revised under MAQP #1821-14, #1821-15, and #1821-16. This change does not require a modification to the originally permitted VCU since the maximum loading rate of 2,000 gallons per minute (gpm) will remain unchanged.

The application also included a request to reduce the limitation for SO<sub>2</sub> emissions from the combustion of alkylation unit polymer and fuel oil in all combustion devices from 127.6 TPY to 50 TPY (for alkylation unit polymer only since fuel oil combustion in refinery boilers will be eliminated). Although the potential to emit for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater is estimated to be around 8.3 TPY for SO<sub>2</sub> (based on a specific gravity of 0.7 and a sulfur content of 1 wt%; the exact potential to emit has not been determined due to the variability of specific gravity and sulfur content), the allowable emissions are set at 50 TPY in this permitting action. According to ARM 17.8.801(24)(f), the decrease in actual emissions from the elimination of fuel oil combustion in refinery boilers is creditable for PSD purposes provided the old level of actual emission or the old level of allowable emissions, *whichever is lower*, exceeds the new level of actual emissions and the decrease in emissions is federally enforceable at and after the time that actual construction begins. Since the old level of actual emissions is lower than the old level of allowable emissions for combustion of fuel oil in refinery boilers, CHS requested a creditable reduction based on actual emissions from the boilers. This reduction resulted in a total of 50 TPY SO<sub>2</sub> allowed for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater, the only unit that is part of the original SO<sub>2</sub> limitation for fuel oil combustion devices that will continue to operate. While it appears that the emissions from the combustion of alkylation unit polymer would be allowed to increase through this permitting action, it is important to note that physical modifications and/or changes in the method of operation would first have to occur for the Alkylation Unit Hot Oil Heater to emit more than its estimated potential of 8.3 TPY (note: the exact potential to emit has not been determined at this time). As acknowledged by CHS, a modification and/or change in method of operation to this unit would require a permit modification. Therefore, the Department does not anticipate any increase in actual emissions from this unit, even though the allowable has been set at 50 TPY. In addition, should CHS eliminate or reduce the combustion of alkylation unit polymer in future permit actions in order to have a creditable decrease for PSD purposes, only the change in actual emissions would be available since the actual emissions will be lower than the allowable, unless a modification to the unit is made.

In addition, CHS requested that the permit CO emission limits for Boiler #11 be changed to 36.63 TPY and 15.26 lb/hr, based on a revised emission factor from performance test data completed in 2007 for Boiler #11 used to calculate the PTE. All of these changes allow CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program.

CHS also requested some additional administrative changes to the permit, including clarification of the applicability of 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters to various sources given the fact that the federal rule was vacated on July 30, 2007. Although the federal rule has been vacated, the vacated federal rule remains incorporated by reference in ARM 17.8.103 and ARM 17.8.302 (with the applicable publication date specified in ARM 17.8.102) at the time of **MAQP #1821-17** issuance and as such, it remains an applicable requirement under state rules; each applicable permit condition has been marked 'State-Only Requirement'.

On April 1, 2008, CHS requested that the Department delay issuance of the preliminary determination for this permit application until additional information could be submitted regarding alternative coke handling practices. This additional information was submitted to the Department on April 3, 2008, with follow-up information received by the Department on April 14, 2008. CHS requested that an alternative coke handling process be included in MAQP #1821-17. The coke handling process, originally permitted

as part of the delayed coker project, included the use of conveyors to transport coke to a crusher and to a railcar loading system. Because the system is enclosed, it is not possible to transport coke to the crusher and loading system without the use of the conveyors. CHS has since identified the need for an alternate coke handling method to be used when the conveyors are out of operation for either planned or unplanned maintenance. MAQP #1821-17 replaced MAQP #1821-16.

On November 7, 2008, the Department received a MAQP application from CHS for a benzene reduction project. In this application, CHS requested to modify MAQP #1821-17, to allow construction of a new Benzene Reduction Unit within the Laurel refinery to meet the requirements of the Mobile Source Air Toxics Rule (40 CFR 80, Subpart L). This rule requires that the refinery's average gasoline benzene concentration in any annual averaging period not exceed 0.62 volume percent, beginning January 1, 2011. This new unit will be inserted in the middle of the existing Platformer Unit. The new process will receive feed from the high pressure separator of the existing Platformer unit and produce a heavy platformate stream that will go directly to product storage and a light platformate stream that will be treated further. The light platformate stream, concentrated with benzene, will undergo a benzene hydrogenation reaction to convert the benzene to cyclohexane. This stream will then be fed to the existing Platformer Unit's debutanizer.

Because the Benzene Reduction Unit includes a hydrogenation reaction, hydrogen is required for the process. For this reason, modification to the existing 1,000 Unit Hydrogen Plant is planned. This modification will essentially increase hydrogen production in the amount needed in the new process and includes the addition of a steam superheater and an Enhanced Heat Transfer Reformer (EHTR). In the existing process, hydrogen is produced by mixing natural gas and the hydrogen-rich Platformer Unit off gas stream with saturated steam. However, in the modified process, only natural gas will be used. Additionally, the steam used will be super-heated to supply additional heat to the primary reformer by means of a higher inlet process gas temperature. This modified process will allow for an increase in the process feed gas flow at the same reformer heat duty. As a result, more hydrogen will be produced in the reformer without increasing the firing rate, and thus, emission rate, of the H-1001 Reformer Heater. For this reason, the H-1001 Reformer Heater is not a project affected emission unit.

In this application, CHS also requested to make enforceable the retrofit of the Platformer Heater with low NO<sub>x</sub> burners. This modification is being done to achieve Consent Decree required NO<sub>x</sub> reductions. This modification is not required by the Benzene Reduction project; however, the retrofit of the Platformer Heater will occur during the construction phase of the Benzene Reduction project.

The Department reviewed this application and deemed it incomplete on December 1, 2008. The Department requested additional information to support the BACT analysis for the Platformer Splitter Reboiler. The Department received the requested follow-up information from CHS on December 15, 2008; the application was deemed complete as of this date.

In addition to making the requested changes, the Department has clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable and deleted all references to 40 CFR 63, Subpart DDDDD: NESHA for Industrial, Commercial, and Institutional Boilers and Process Heaters, as it was removed from the ARM in October 2008. **MAQP #1821-18** replaced MAQP #1821-17.

On February 27, 2009, the Department received a complete MAQP application from CHS requesting clarification of an existing NO<sub>x</sub> emissions limit for Boiler #12. In this application, CHS requested that the averaging period for the NO<sub>x</sub> lb/MMBtu limit be specified as a 365-day rolling average. CHS submitted information to support this averaging period as the original basis for the BACT analysis conducted in MAQP #1821-17 for Boiler #12. **MAQP #1821-19** replaced MAQP #1821-18.

On August 13, 2009, the Department received a complete application from CHS requesting a modification to MAQP #1821-19. CHS proposed to retrofit the existing Boiler #10 with a lower NO<sub>x</sub> control technology burner and to update the permit limits for this unit accordingly. This project was completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability. On September 17, 2009, the Department received a revision to this application addressing the SO<sub>2</sub> BACT analysis for both Boiler #10 and the recently permitted Platformer Splitter Reboiler. This application revision was submitted in consultation with the Department and revised the SO<sub>2</sub> BACT analysis to reflect the recently finalized NSPS Subpart Ja requirements. **MAQP #1821-20** replaced MAQP #1821-19.

On March 31, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-20. Additional information was received on April 22, 2010 resulting in a complete application. The application and additional information included requests for several modifications within the permit.

During the issuance of MAQP #1821-17, it became apparent that the Department and CHS had differing interpretations of paragraphs 177 and 180 of the CHS Consent Decree (CD) with EPA and the State of Montana (Consent Decree CV-03-153-BLG-RFC). Based on these differing interpretations, CHS deemed it necessary to retroactively analyze previous permit actions, particularly associated with the Delayed Coker Project, where changes may be necessary as a result of interpreting the CD in an alternative manner. On October 26, 2009, CHS provided an analysis concluding that the Delayed Coker Project was properly permitted as a non-major modification under New Source Review (including both PSD and Non-attainment Area New Source Review (NNSR)). For four pollutants (CO, VOC, TSP, and PM-10), project related emissions increases determined under Step 1 of the required applicability analysis were below the applicable significance thresholds. For two pollutants (NO<sub>x</sub> and SO<sub>2</sub>), the net emissions change, including project related emissions increases and contemporaneous emissions changes, were below the applicability significance thresholds. Following review, the Department concurred with CHS' analysis. However, as a result of this re-examination, including updates and changes to the original Delayed Coker Project emissions calculations, the following updates to MAQP #1821-20 were necessary to accurately reflect the refinery's overall process and individual emitting units.

1. Coke Drum Steam Vent

The original Delayed Coker Permit application did not include an estimate of the emissions associated with depressurizing the coke drum as part of the decoking operation. Based on emissions quantified at another facility, CHS was able to estimate emissions from their Coke Drum Steam Vent. MAQP #1821-21 has been updated to include this emitting unit in addition to the limitations and conditions assigned to it.

2. FCCU Regenerator

As part of the CD requirements, CHS completed catalyst additive trials at the FCCU in order to reduce NO<sub>x</sub> emissions. Upon completion of the trials, CHS proposed short term (7-day rolling average) and long term (365-day rolling average) concentration-based NO<sub>x</sub> limits to EPA. CHS proposed a long term concentration limit of 65.1 parts per million, volumetric dry (ppm<sub>vd</sub>) on a 365-day rolling average basis and a short term concentration limit of 102 ppm<sub>vd</sub> on a 7-day rolling average basis. EPA has agreed to these proposed limitations and these limits were included within MAQP #1821-21.

3. Boiler 12 and Railcar Light Product Loading Projects

Originally permitted within MAQP #1821-17, the Boiler 12 and Railcar Light Product Loading Projects were included in the same permit application for administrative convenience only and should not be included as part of the Delayed Coker Project's

emissions increase calculations. The Department agrees that the two projects were not substantially related and had no apparent interconnection to each other or to the Delayed Coker Project. The emissions calculations were updated to reflect this conclusion.

4. Shutdown Timing for #4 and #5 Boilers

Included in the permitting action resulting in MAQP #1821-17 were shutdown dates for Boiler #4 and Boiler #5, which was tied to the initial startup of Boiler #12. Because emissions reductions from the boiler shutdowns were not required to avoid triggering the PSD requirements, the shutdown dates are no longer related to the startup of Boiler #12. The timing is driven by the CD, requiring all NO<sub>x</sub> reduction projects (including shutdown of Boiler #4 and Boiler #5) to be completed by December 31, 2011.

5. Benzene Reduction Unit Project Updates

As a portion of the plan to achieve required NO<sub>x</sub> emissions reductions as outlined in the CD, CHS had elected to retrofit the Platformer Heater (P-HTR-1) with low NO<sub>x</sub> burners. The proposed retrofit was included in the application for the Benzene Reduction Project (MAQP #1821-18). CHS has determined that the retrofit will no longer be necessary to achieve the CD required NO<sub>x</sub> reductions. All emission limitation and monitoring, reporting and notification requirements were removed.

6. Boiler #11 and Boiler #12 BACT Analysis Update

The original BACT analyses included in the permit applications associated with Boiler #11 and Boiler #12 did not specifically address CO emissions during startup and shutdown operations. During these operations, the boiler may experience an increase in CO emissions as a result of the ultra low NO<sub>x</sub> burner (ULNB) design. Based on an analysis of data collected during startup and shutdown operations for Boiler #11 and Boiler #12, a short term CO limit of 23 lb/hr on a 24-hour average basis, was included for periods of boiler startup and shutdown. Additionally, CHS proposed installation and operation of a volumetric stack flow rate monitor on Boiler #11 in order to be consistent with Boilers #10 and #12.

In addition to the aforementioned updates, CHS also requested a modification to the stack testing requirements to require stack testing every two years as opposed to annual stack testing for the following sources: Reactor Charge Heater (H-201), Fractionator Feed Heater (H-202), Reactor Charge Heater (H-901), Fractionator Reboiler (H-902), and NHT Charge Heater (H-8301). The Department approved this new testing schedule and MAQP #1821-21 was updated accordingly. Additionally, various miscellaneous administrative changes were requested and included in this permitting action. **MAQP #1821-21** replaced MAQP #1821-20.

On July 27, 2010, the Department received a request to administratively amend MAQP #1821-21. The Department had inadvertently failed to modify all pertinent sections within MAQP #1821-20 to reflect the December 31, 2011 shutdown date for Boiler #4 and Boiler #5. CHS had requested the Department to administratively amend the permit to reflect this shutdown date in all applicable sections within the permit. CHS also requested the Department administratively amend the permit to include a reference to parts per million, volumetric dry (ppmvd) units where hydrogen sulfide (H<sub>2</sub>S) limits are expressed in grains per dry standard cubic feet (gr/dscf). The Department made the aforementioned administrative changes. **MAQP #1821-22** replaced MAQP #1821-21.

On November 1, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-22.

### “Mild Hydrocracker Project”

In this application, CHS proposed to convert the existing HDS Unit into a Mild Hydrocracker. Capacities of the existing 100 Unit Hydrogen Plant and the Zone D SRU/TGTU were proposed to be increased, the existing feed heater in the FCC Unit replaced and a rate-limiting pressure safety valve (PSV) in the NHT replaced. Collectively, these modifications are referred to as the “Mild Hydrocracker Project.” The primary purpose in converting the existing HDS Unit into a Mild Hydrocracker was to produce an increased volume of higher quality diesel fuel by utilizing more hydrogen to convert gasoil into diesel.

The Mild Hydrocracker Project consists of several components. Within the HDS, the following changes were slated:

- As a result of a significant increase in hydrogen consumption, modifications to the existing hydrogen supply and recycle system will be required. The existing C-201B gas-fired reciprocating engine and hydrogen recycle compressor will be replaced with an electric driven make-up hydrogen compressor. Additionally, a new electric-driven recycle compressor (C-203) will be added.
- The first two reactors will continue to contain a hydrotreating catalyst. The third reactor will be split from one bed of catalyst to two beds of catalyst, containing both hydrotreating and hydrocracking catalyst.
- Equipment to be added or modified as a result of volume or heat impacts include the following:
  - A hydrogen bypass line will be added to allow for hydrogen addition both upstream and downstream of the H-201 Reactor Charge Heater.
  - Changes in the separation process downstream of the reactors: Two new drums will be added, Hot and Cold Low Pressure Separators, along with additional heat exchange, including two sets of process heat exchangers, one cooling water heat exchanger and one fin-fan cooler.
  - Trays within the H<sub>2</sub>S Stripper will be replaced with higher capacity trays.
  - The overhead condenser and pump associated with the H<sub>2</sub>S Stripper Overhead Drum will be modified.
  - A new “wild” naphtha product draw will be added to the H<sub>2</sub>S Stripper Overhead Drum. This stream will be processed in the Crude Unit Naphtha Stabilizer and then routed to the NHT Unit.
  - A bypass line for hydrocarbon feed to the Fractionator around the H-202 Fractionator Feed Heater may be added as a result of improved heat integration.
  - The trays in the Fractionator will be replaced with higher capacity trays.
  - A new flow loop on the Fractionator will be added returning a portion of the diesel draw to the Fractionator. The pump will also feed the Diesel Stripper. The loop will include a new pump, a fin-fan cooler and a steam generator.
  - The trays in the existing Diesel Stripper will be replaced with higher capacity trays.
  - New larger pump(s) will be added on the loop between the Diesel Stripper and the Diesel Reboiler. These pump(s) may also be used for diesel product.
  - The Diesel Product Cooler (fin-fan) will be replaced with a higher capacity cooler.
  - New higher capacity packing will be installed in the HP Absorber. Water circulation on the absorber will be eliminated.

Within the SRU, the following physical changes were proposed:

- Replace and upgrade the acid gas burner;
- Replace the reaction furnace and upgrade to higher pressure and temperature capability;
- Replace and upgrade the waste heat boiler for higher pressure steam generation;
- Replace and upgrade the three steam reheaters;
- Upgrade the #1 sulfur condenser; and
- Add new electric boiler feedwater pumps to accommodate the higher pressure steam generation.

Within the TGTU, the following physical changes were proposed:

- The trays in the quench tower and amine absorber will be replaced with higher vapor capacity trays;
- The cooling system will be improved through increased circulation and minor piping modifications to control the maximum temperature of the circulating amine; and
- The methyl diethanolamine amine (MDEA) used in the absorption section of the TGTU will be replaced with a proprietary high performance amine blend.

Within the 100 Unit Hydrogen Plant, the following changes were proposed:

- Addition of a new H-102 Reformer Heater to operate in parallel with the existing H-101 Reformer Heater;
- Modification of existing boiler feed water (BFW) pumps for increased capacity and a new larger condensate cooler;
- Addition of new pumps to circulate water through the steam generation coil on the new reformer heater;
- Modification of the existing steam drum internals to handle higher steam loads;
- Replace end of life trays within the deaerator tower with higher capacity trays;
- Replace the hot and cold condensate drums with upgraded internals and more corrosion resistant metallurgy;
- Replace absorbent and valves on the PSA skid; and
- Remove equipment related to the use of propane as the feed stream to the 100 Unit Hydrogen Plant.

#### “ULSD Burner Fuel Project”

The application also included information related to an additional project that is proposed to be completed at the refinery concurrent with the project discussed above. The project involves adding the flexibility to recover additional Burner Fuel, rather than Diesel Fuel, within the existing ULSD unit. The feed rate to the ULSD Unit will not increase with this project.

In addition to the aforementioned projects, CHS requested the Department incorporate several administrative changes.

**MAQP #1821-23** replaced MAQP #1821-22.

On January 10, 2011, the Department received a request to administratively amend MAQP #1821-23. In review of the Department Decision for MAQP #1821-23 issued on December 30, 2010, CHS identified areas within the permit that required further clarification based on their comments submitted on the Preliminary Determination issued for MAQP #1821-23.

**MAQP #1821-24** replaced MAQP #1821-23.

On April 12, 2011, the Department received an application from CHS for a modification to MAQP #1821-24. The modification request details proposed changes to a *de minimis* request approved by the Department on December 10, 2010 as well as proposed construction of two product storage tanks.

On December 6, 2010, the Department received a *de minimis* notification from CHS proposing construction of a new 100,000 barrel (bbl) storage tank (Tank 133) for the purpose of storing asphalt. Emissions increases as a result of the proposed project were calculated to be less than the *de minimis* threshold of 5 tpy, with no emissions from each of the regulated pollutants exceeding 1.44 tpy. Although CHS justified the project from an economics standpoint for asphalt service only, CHS determined that during the times of year that asphalt storage is not necessary, it would be advantageous to have the extra tank capacity available to store other materials, such as gas oil and diesel. These materials may accumulate in anticipation of or as a result of a unit shutdown. Within the April 12, 2011 application, CHS proposes installation of additional pumps and piping to allow for gas oil and diesel to be stored as well as asphalt as previously approved for Tank 133.

A separate project detailed within the April 12, 2011 application includes construction of two new product storage tanks, collectively referred to as the Tanks 135 and 136 Project. The Tanks 135 and 136 Project would include construction of two new 120,000 bbl external floating roof (EFR) product storage tanks and associated pumps and piping to allow more flexible storage of various gasoline and/or diesel components and finished products produced at the refinery. Tank 135 would be installed in the East Tank Farm located on the east side of Highway 212. With the current refinery piping configuration, this tank would store only finished gasoline and diesel products. Tank 136 would be installed in the South Tank Farm located on the west side of Highway 212. With the current refinery piping configuration, this tank would be available to store both component and finished gasoline and diesel products. To avoid restriction of service of the tanks, project emissions increase calculations were based conservatively on storage of gasoline year round as well as current maximum refinery production capability.

Within the April 12, 2011 application, CHS also provided supplemental information to the BACT analysis included in the original permitting application for the Coker Charge Heater (H-7501) originally permitted as a part of the Delayed Coker project (1821-13 with revisions 1821-14 through 1821-16). This supplemental information was submitted with the purpose of laying the foundation for a proposed additional short term CO emissions limit.

**MAQP #1821-25** replaced MAQP #1821-24.

On November 8, 2011, the Department of Department received an application from CHS for a modification to MAQP #1821-25. The application included three separate projects, grouped together into one action for administrative convenience. CHS proposed the following projects within this application:

1. #1 Crude Unit Revamp Project
2. Wastewater Facilities Project
3. Product Blending Project

The application also included the following:

1. Review of the regulatory applicability to existing Sour Water Storage Tanks 128 and 129.
2. Updates to the Mild Hydrocracker Project, which was permitted as part of MAQP #1821-23 and MAQP #1821-24.
3. Review of the regulatory applicability to the Product Storage Projects, which was permitted as part of MAQP #1821-25.

## #1 Crude Unit Revamp Project

The #1 Crude Unit Revamp Project was proposed with the intention of improving the overall efficiency of the refinery by maximizing diesel and gas oil recovery in the atmospheric and vacuum processes at the #1 Crude Unit. The project would aid in accounting for changes in crude quality that have been evident historically and are expected in the future. Modifications in the vacuum process are expected to result in an improved separation of the diesel and gas oil components such that diesel will not be carried with the gasoil to units downstream of the Crude Unit. Modifications in the vacuum process will result in the recovery of additional gas oil from the asphalt and improved quality of feed to the downstream Delayed Coker Unit.

The #1 Crude Unit Revamp Project includes the following key components:

- Improvements to the preheat exchanger trains to ensure additional heat can be added to the crude oil upstream of the atmospheric column.
- Modifications to the atmospheric column from the diesel draw downward and to the associated condensing systems.
- Existing dry vacuum process will be changed to a wet vacuum system through the addition of steam.
- Redesign and replacement of the existing vacuum column.
- Installation of new equipment to recover a diesel stream from the new vacuum column.
- Addition, replacement and/or redesign of overhead and product cooling systems.

## Wastewater Facilities Project

The proposed Wastewater Facilities Project is slated to improve the overall performance of the refinery wastewater handling and treatment facilities and to address anticipated future wastewater discharge quality requirements. The project is comprised of the following components:

- Installation of new Three Phase Separator(s) to remove solids and free oil from wastewater generated at the crude unit desalters.
- Installation of new American Petroleum Institute (API) Separator(s) and Corrugated Plate Interceptor (CPI) Separator(s) to treat process wastewater generated at the older process units. The existing API Separator will be removed from service. As a note, emissions from the separators will be controlled with carbon canisters.
- Replacement of the existing activated sludge unit (ASU) (T-30). Replacement will be of the same size and will incorporate several design changes to improve the biological treatment efficiency.
- Installation of a second ASU and clarifier to be operated in parallel with the existing ASU and clarifier and will provide maintenance backup to the system.
- Installation of two new Sludge Handling Tanks to receive waste activated sludge from the clarifiers. The removed sludge will be dewatered and dried for offsite disposal.
- Installation of two new DAF Units to treat process wastewater from all of the process units. Emissions from the DAF Units will be controlled with carbon canisters. The existing DAF will be removed from service.

## Product Blending Project

The objective of the Product Blending Project is to increase the volume of finished diesel and burner fuel available for sale. The project is comprised of the addition of new piping components; however, the changes will not result in a change to the operation of any process units at the refinery.

## Additional Permit Changes

CHS conducted a review of regulatory applicability pertaining to sour water storage tanks 128 and 129, which were permitted as a result of CHS's permit application submitted on October 18, 2005, for the delayed coker project. Based on the review, CHS determined Tanks 128 and 129 to not be subject to 40 CFR 60 (NSPS) and also determined Tanks 128 and 129 to be labeled as Group 2 storage vessels as described within 40 CFR 63, Subpart CC. Therefore, CHS requested the permit, specifically the Title V Operating Permit, be updated to reflect these new determinations of regulatory applicability.

As part of MAQP #1821-23, CHS proposed to convert the existing Hydrodesulfurization (HDS) Unit into a Mild Hydrocracker. Since issuance of this permit, various portions of this project scope were modified, with only one change resulting in a change in the original project emissions calculations. Potential emissions increased slightly; however, continued to remain below significance levels with respect to Prevention of Significant Deterioration (PSD) review. A summary of the updated emissions inventory was included in the permit analysis for this permit action.

CHS additionally conducted a review of regulatory applicability pertaining to Tanks 133, 135, and 136. As part of the original permitting action (MAQP #1821-25) associated with these product storage tanks, CHS identified the applicability of NSPS Subpart GGGa to the piping components associated with the three new storage tanks. This applicability has been reevaluated. NSPS Subpart GGGa applies to affected facilities at petroleum refineries that are constructed, reconstructed or modified after November 7, 2006. Specifically, as stated within NSPS Subpart GGGa, the group of all the equipment (defined in §60.591a) within a process unit is an affected facility. The definition of "process unit," as defined in 60.590a(e) is as follows:

*"Process unit means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product."*

The applicability of NSPS Subpart GGGa has been determined to stop at the boundary of a process area and does not include piping components between the process area and storage tanks, therefore, eliminating the components associated with Tanks 133, 135, and 136 from being applicable to NSPS Subpart GGGa. Although this equipment is not specifically applicable under NSPS Subpart GGGa, the VOC BACT (Refinery Equipment) determination from MAQP #1821-25 stated that "an effective monitoring and maintenance program or Leak Detection and Repair (LDAR) program (as described under NSPS Subpart VVa) meeting the requirements of NSPS Subpart GGGa constitutes VOC BACT for equipment leaks from new components." The Department modified the requirements for institution of a monitoring and maintenance program to more accurately reflect the VOC BACT (Refinery Equipment) determination; thus removing the NSPS Subpart GGGa reference and including the pertinent language within the condition itself. The conditions are now reflective of only the BACT determination.

CHS also requested several various administrative changes and clarification additions.

**MAQP #1821-26** replaced MAQP #1821-25.

On June 4, 2012, CHS Inc. submitted a permit application to the Department to modify MAQP # 1821-26 and Title V Operating Permit (OP) #OP1821-10. The application was submitted to modify two previously permitted refinery projects, and to construct a new gasoline and diesel truck loading facility as summarized below:

**Mild Hydrocracker (MHC) Project Update.** This permit action incorporated the final design and location of the Fluid Catalytic Cracking (FCC) Charge Heater being replaced as part of the MHC Project. The FCC Charge Heater was originally approved at 60 million british thermal units per hour (MMBtu/hr) as

part of the MHC project (MAQP #1821-23). This permit application modified the size of the heater from 60 to 66 MMBtu/hr. In addition, the permit application reclassified the FCCU Reactor/Regenerator as a “modified” emitting unit rather than an “affected unit,” and CHS requested to replace the existing Riser with a new Riser (and Riser design) as the current Riser was nearing the end of its mechanical life.

**Benzene Reduction Unit (BRU) Project Update.** This project involved a modification of the H-1001 Reformer Heater to achieve the design hydrogen production rate within the 1000 Unit Hydrogen Plant. Expansion of the 1000 Unit Hydrogen Plant was included in the MAQP #1821-18. However, the 1000 Unit Hydrogen Plant expansion changed the characteristics of the PSA tailgas (e.g. the heat content (Btu per standard cubic feet (Btu/scf) declined and the volume produced increased (standard cubic feet per minute (scfm)). According to CHS, the total heat input associated with the PSA tailgas remained nearly the same. As a result, the existing PSA tailgas burners on the H-1001 Reformer Heater could not handle the increased volume of PSA tailgas without excessive pressure drop and the 1000 Unit Hydrogen Plant production rate became limited by the volume of PSA tailgas that could be combusted. The permit modification replaced the PSA tailgas burner tips with tips that have larger ports such that all of the PSA tailgas generated could be combusted in H-1001. CHS proposed replacement of the supplemental fuel (e.g. natural gas, refinery fuel gas) burners in H-1001 to achieve improved NOx emission performance. The previous heater was physically capable of combusting refinery fuel gas but could not meet the existing oxides of nitrogen (NOx) permit limits while doing so. Additionally, the modified heater will have a higher maximum design firing rate (191.8 MMBtu-HHV/hr post project versus 177.7 MMBtu-HHV/hr) and a slight increase in the actual firing rate.

**Gasoline and Distillate Truck Loading Facilities Project.** This permit application also proposed the construction of new gasoline and distillate truck loading facilities, including new storage tanks, loading rack and VCU. The goal of the project was to improve safety and reduce truck congestion by relocating the gasoline and distillate truck loading operation to the east side of Highway 212. As proposed by CHS, the existing truck loading rack and associated equipment will be permanently removed from service within 180 days of startup of the new loading facility. The permit modification also added a new propane storage and loading facility.

In addition to those items mentioned above, this permit action included miscellaneous updates and amendments. CHS requested to discontinue use of the sulfur dioxide (SO<sub>2</sub>) Continuous Emissions Monitoring System (CEMs) on the H-1001 stack because H-1001 was subject to 40 Code of Federal Regulations (CFR) 60, Subpart Ja which included exemptions from hydrogen sulfide/sulfur dioxide (H<sub>2</sub>S/SO<sub>2</sub>) monitoring requirements for fuel gas streams that are inherently low in sulfur content. The primary fuel to H-1001, PSA tailgas is inherently low in sulfur content. CHS already monitors the H<sub>2</sub>S content of the refinery fuel gas (RFG) to be combusted in H-1001 as supplemental fuel, which would meet the monitoring requirements of Subpart Ja.

CHS requested that the Department remove condition IV.E.4 which requires the use of statistically significant F-factor values in determining compliance with NOx and carbon monoxide (CO) limits for the H-102 Reformer Heater. Rather, CHS proposed that results of the required performance testing be used to calculate an appropriate emission factor to demonstrate ongoing compliance with NOx and CO limits

CHS also requested several various administrative changes and clarification additions.

**MAQP #1821-27** replaced MAQP #1821-26.

On November 14, 2012, CHS Inc. submitted a request to the Department to amend several items in the MAQP. CHS requested that the Department remove existing gasoline and distillate loading rack and associated VCU from the new VOC limit in Sections VI and XVI of the MAQP. CHS provided clarification that they intend to permanently shutdown the existing propane loading rack but not the existing propane storage facilities as was previously stated in the CHS permit application. In MAQP

#1821-27, CHS proposed replacement of the burners in the H-1001 Reformer Heater. However, the firing rate and associated limits only apply once the heater has restarted after the retrofit. The Department clarified this by adding the limitations previously listed in MAQP #1821-26 back into the permit. In addition to those changes mentioned above, CHS requested several various administrative changes and clarifications.

**MAQP #1821-28** replaced MAQP #1821-27.

### **Title V Operating Permit History**

CHS's Title V **Operating Permit #OP1821-00** was issued final & effective on November 11, 2001.

On May 12, 2006, the Department received an application for the renewal of Title V Operating Permit #1821-00. The application was deemed administratively complete on June 12, 2006 and technically complete on July 11, 2006. Permit #OP1821-01 incorporates all applicable source changes since the issuance of Permit #OP1821-00, including:

- Addition of three new emitting units: #EU021 (ULSD and Hydrogen Plant), #EU022 (Delayed Coker Unit), and #EU023 (Zone E SRU and TGTU);
- Incorporation of Consent Decree CV-03-153-BLG-RFC requirements. This included updating the Title V Operating Permit with a number of specific new emission limits and monitoring requirements which had been included in the most recent MAQP #1821-15, as well as adding a general requirement for CHS to comply with the relevant applicable terms and conditions of the Consent Decree (most importantly, the Affirmative Relief/Environmental Projects, Subsections A-M, (excluding the stipulated penalty components)); and
- Inclusion of new regulations impacting CHS, including three MACT standards: 40 CFR 63, Subpart UUU, Subpart ZZZZ, and Subpart DDDDD.

On October 4, 2007, CHS appealed Operating Permit #OP1821-01 on the basis of the inclusion of the entire Consent Decree CV-03-153-BLG-RFC. CHS' contention was that ARM 17.8.1211(2) only allows consent decree requirements to be included that are as a result of non-compliance with a specific rule or regulatory requirement. The Department included the Consent Decree because it considered the Consent Decree requirements as relevant terms and conditions required to be included in the Title V Operating Permit. The following language (and changes to the permit as described below) satisfy both CHS and the Department with respect to inclusion of Consent Decree requirement into the Title V Operating Permit:

*"CHS has entered into a Consent Decree (United States et al v. CHS Inc., Civil Action CV-03-153-BLG-RFC (D. Mont. February 23, 2004)). Certain consent decree emission limits, standards, and schedules have been incorporated as term and conditions of the permit, into the appropriate sections of this permit. Other consent decree requirements are considered program enhancements and are not included as terms or conditions of the permit. These requirements, found in Appendix F of the permit, may be enforced by the State of Montana and the United States Environmental Protection Agency pursuant to the provisions of the consent decree."*

**Operating Permit #OP1821-01** replaced Operating Permit #OP1821-00.

On October 10, 2007; February 25, 2008; November 7, 2008; and February 27, 2009, the Department received significant modification applications from CHS. The significant modifications included:

- An increase in the firing rate of the NHT Charge Heater (H-8301) to address an operating scenario that was overlooked during the delayed coker unit design process (**application #OP1821-02**);

- The installation of a new steam generating boiler (Boiler #12), expansion of the existing railcar light product loading facilities, as well as an alternative coke handling practice (**application #OP1821-03**);
- The construction of a Benzene Reduction Unit to comply with the Mobile Source Air Toxics Rule (**application #OP1821-04**); and
- Clarification of the averaging period applicable to the Boiler #12 NO<sub>x</sub> permit limit (#OP1821-05).

All of these significant modifications were issued under Operating Permit #OP1821-05. **Operating Permit #OP1821-05** replaced Operating Permit #OP1821-01.

The following series of applications and supplemental information triggered MAQP actions and subsequently called for modifications to Operating Permit #OP1821-05.

- August 13, 2009: CHS proposed retrofitting the existing Boiler #10 with a lower NO<sub>x</sub> control technology burner and to update the permit limits for this unit accordingly. This project was completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability.
- September 17, 2009: This information comprised of a revision to the August 13, 2009 application addressing the SO<sub>2</sub> BACT analysis for both Boiler #10 and the recently permitted Platformer Splitter Reboiler. This application revision was submitted in consultation with the Department and revised the SO<sub>2</sub> BACT analysis to reflect the recently finalized NSPS Subpart Ja requirements.

(These modifications would have been issued under **Operating Permit #OP1821-06**; however, were combined with the two modification requests that follow.)

- March 31, 2010: CHS proposed modifications associated with the results of retroactively analyzing previous permit actions, particularly associated with the Delayed Coker Project. This application and additional information included requests for several modifications within the permit. These requests have been outlined above within the MAQP history outlining the changes that resulted in MAQP #1821-21.
- July 27, 2010: This administrative amendment request consisted of the addition of ppm<sub>vd</sub> units where H<sub>2</sub>S limits are expressed in gr/dscf and also included the December 31, 2010 shutdown date for Boiler #4 and Boiler #5.

**Operating Permit #OP1821-07** incorporated these aforementioned MAQP actions and replaced Operating Permit #OP1821-05.

On November 1, 2010, the Department received an application from CHS requesting a modification to Operating Permit #OP1821-07.

The application outlined CHS's proposal to convert the existing HDS Unit into a Mild Hydrocracker. As part of this project, referred to as the "Mild Hydrocracker Project", the capacities of the existing 100 Unit Hydrogen Plant and the SRU/TGTU will be increased, the existing feed heater in the FCC Unit will be replaced and a rate-limiting pressure safety valve (PSV) in the Naphtha Hydrotreating Unit (NHT) will be replaced.

The application also included information related to an additional project that is proposed to be completed at the refinery concurrent with the Mild Hydrocracker Project. The project involves adding the flexibility to recover additional Burner Fuel, rather than Diesel Fuel, within the existing ULSD unit. The feed rate to the ULSD Unit will not increase with this project. This project is referred to as the “ULSD Burner Fuel Project.”

In addition to the aforementioned projects, CHS requested the Department to incorporate several administrative changes.

A detailed description of the various components of these projects is included in the MAQP history for the actions resulting in MAQP #1821-23 and MAQP #1821-24.

**Operating Permit #OP1821-08** replaced Operating Permit #OP1821-07.

On April 12, 2011, the Department of Environmental Quality (Department) received an application from CHS for a modification to MAQP #1821-24 and Air Quality Operating Permit OP1821-07. As referenced in the permit history above, OP1821-07 was updated with a modification as requested on November 1, 2010, thus this application resulted in a modification of OP1821-08. The modification request detailed proposed changes to a *de minimis* request approved by the Department on December 10, 2010 as well as proposed construction of two product storage tanks.

On December 6, 2010, the Department received a *de minimis* notification from CHS proposing construction of a new 100,000 barrel (bbl) storage tank (Tank 133) for the purpose of storing asphalt. Emissions increases as a result of the proposed project were calculated to be less than the *de minimis* threshold of 5 tpy, with no emissions from each of the regulated pollutants exceeding 1.44 tpy. Although CHS justified the project from an economics standpoint for asphalt service only, CHS determined that during the times of year that asphalt storage is not necessary, it would be advantageous to have the extra tank capacity available to store other materials, such as gas oil and diesel. These materials may accumulate in anticipation of or as a result of a unit shutdown. Within the April 12, 2011 application, CHS proposed installation of additional pumps and piping to allow for gas oil and diesel to be stored as well as asphalt as previously approved for Tank 133.

A separate project detailed within the April 12, 2011 application included construction of two new product storage tanks, collectively referred to as the Tanks 135 and 136 Project. The Tanks 135 and 136 Project included construction of two new 120,000 bbl external floating roof (EFR) product storage tanks and associated pumps and piping to allow more flexible storage of various gasoline and/or diesel components and finished products produced at the refinery. Tank 135 would be installed in the East Tank Farm located on the east side of Highway 212. With the current refinery piping configuration, this tank would store only finished gasoline and diesel products. Tank 136 would be installed in the South Tank Farm located on the west side of Highway 212. With the current refinery piping configuration, this tank would be available to store both component and finished gasoline and diesel products. To avoid restriction of service of the tanks, project emissions increase calculations were based conservatively on storage of gasoline year round as well as current maximum refinery production capability.

Within the April 12, 2011 application, CHS also provided supplemental information to the BACT analysis included in the original permitting application for the Coker Charge Heater (H-7501) originally permitted as a part of the Delayed Coker project (MAQP #1821-13 with revisions MAQP #1821-14 through MAQP #1821-16). This supplemental information was submitted with the purpose of laying the foundation for a proposed additional short term CO emissions limit.

**Operating Permit #OP1821-09** incorporated these aforementioned MAQP actions and replaced Operating Permit #OP1821-08.

On November 8, 2011, the Department received an application from CHS for a significant modification to Operating Permit #OP1821-09. The application included three separate projects, grouped together into one action for administrative convenience. CHS proposed the following projects within this application:

1. #1 Crude Unit Revamp Project
2. Wastewater Facilities Project
3. Product Blending Project

The application also included the following:

1. Review of the regulatory applicability to existing Sour Water Storage Tanks 128 and 129.
2. Updates to the Mild Hydrocracker Project, which was permitted as part of MAQP #1821-23 and MAQP #1821-24.
3. Review of the regulatory applicability to the Product Storage Projects, which was permitted as part of MAQP #1821-25.

Each of these application components are thoroughly described within the Montana Air Quality Permit History section above.

**Operating Permit #OP1821-10** incorporated the permit conditions and changes associated with these projects and reviews and replaced Operating Permit #OP1821-09.

#### **D. Current Permit Action**

On June 4, 2012, CHS submitted concurrent applications for a modification to MAQP #1821-26 and a significant modification to Operating Permit #1821-10. The permit application proposed modifications to two previously permitted refinery projects (Mild Hydrocracker Project and the Benzene Reduction Unit Project) and the addition of a new gasoline and diesel truck loading facility. CHS submitted several clarifications and additional information through November 14, 2012, including an administrative amendment for MAQP #1821-27.

#### **E. *Operating Permit #OP1821-11 incorporates the permit conditions and changes associated with these projects and replaces Operating Permit #OP1821-10.* Taking and Damaging Analysis**

House Bill (HB) 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].

		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

## F. Compliance Designation

The last full compliance evaluation inspection was conducted on September 30, 2009 covering the time period from September 1, 2006, to September 30, 2009. At that time, it was determined that CHS was generally complying with the terms and conditions of their air quality permits, applicable rules, and consent decrees.

On September 29, 2006, CHS was inspected by the Department and found to be in compliance with applicable requirements. Since that time, however, the Department has initiated an enforcement action against CHS for Boiler #10 NO<sub>x</sub> violations. These violations were addressed through an administrative order on consent requiring CHS to pay a penalty of \$165,000. On April 7, 2009, the Department received the full and final payment of the administrative penalty in accordance with the consent order. With the receipt of this payment, the Department considered the enforcement action resolved.

The Department completed a report documenting the results of the full compliance evaluation (FCE), with any partial evaluations (PCE), and any investigations conducted for the period from: 9/30/06 to 9/28/12. The findings and recommendations section of the report has been summarized below:

CHS entered into a CD (United States et al v. CHS Inc., Civil Action CV-03-153-BLG-RFC, 2/23/2004) under the EPA's National Refinery Initiative to come into compliance with various federal Clean Air Act requirements and to reduce emissions of SO<sub>2</sub>, NO<sub>x</sub>, CO, VOC, PM, and HAP. The emission reduction strategies are to be phased-in over several years and are to be made enforceable under various permitting changes. PM reductions have been implemented for the FCCU with the new ESP control device. NO<sub>x</sub> reductions are being implemented under the NO<sub>x</sub> Control Plan for the FCCU and on specified heater projects that upgrade the emissions performance of these units. CHS has met the schedule for NO<sub>x</sub> Control Plan by 12/31/11 and with all other CD emission reduction implementations, and there have been no amendments to the CD to defer these deadlines to later dates. CHS also permanently shut down and completely removed three old boilers (#3, #4, and #5) and their respective stacks from the refinery. Boiler #3 was previously shut down in 2007, Boiler #4 was shut down in 2009, and Boiler #5 shut down occurred in 2011. Project demolition and stack removal was completed during this review period.

CHS had surpassed the benchmark of five acid gas flaring events in a rolling twelve 12-month period frequency and paid EPA the stipulated penalty amount in June 2010. Since then, CHS has not exceeded five or more acid gas flaring events in a 12-month rolling period during this compliance monitoring review period. No additional stipulated penalties have been assessed by the EPA under the CD during this review period.

CHS has also submitted several AMPs to the EPA for approval that deal with various process streams that are burned-off in the flare. Normally these streams are utilized in the refining process but due to process problems, upsets, or malfunctions, CHS has to dispose of these streams or gases at the flare. These process gasses must comply with the fuel gas H<sub>2</sub>S concentration limits and monitoring requirement provisions contained 40 CFR 60, Subpart J or Ja. When approved, the AMP must address compliance, monitoring and reporting of these process streams or gasses that are not otherwise continuously monitored by the CEMS for the refinery fuel gas system. The Coker Unit olefin AMP was revised during this review period. Visual observations noted by air complaints involve a significant orange flame at the flare stack and noise. CHS should minimize these periods the best it can and operate the flare to minimize excessive visible emissions (soot) during flaring events.

The Department conducted an inspection of the Coker Unit and an investigation of the Zone A SRU during this review period. CHS reported Coker Unit drum blowouts on five dates (2/08-09/10; 12/21/10; 7/01/11; 3/01/12; and 4/13/12) during the review period. On two of these dates (2/09/12 and 4/13/12), the Department received formal complaints from the public. On the three remaining dates, the coke dust emissions were either minor and/or the coke dust plume settled-out primarily onto the refinery property. Coke drum blowouts are not a permitted activity under the facility air quality permits. DEQ issued two Warning Letters (#WLJH10-05 and #WLJH12-21) associated with the dates that correspond to the public complaints because the coke dust emissions were documented to be leaving the refinery property. CHS has implemented operational changes in the coking process to address and minimize these recurrences. Also, CHS installed coke drum blowout diverters during the September-October 2011 turnaround on each drum that direct the coke-drum blowout emissions from atop the drum down into the coke pit area. Since the installation dates of the coke drum blowout diverters, there were two dates (3/01/12 and 4/13/12) where coke dust escaped the coke pit due to the diverted blowout that settled out beyond the refinery property. DEQ conducted an inspection of the Coker Unit on 8/16/2012 and found the unit to be in compliance with the applicable requirements of MAQP #1821-26 and Operating Permit #OP1821-10. No visible emissions were observed at this time and housekeeping in this area was excellent. Housekeeping in the Coker Unit is important to minimize any finely pulverized coke windblown emissions. DEQ believes that the coke drum blowout events investigated to date pertain to operational issues and not from bona fide equipment malfunctions. DEQ will continue to monitor the activity of drum blowouts and will respond accordingly to these events.

The Zone A SRU SO<sub>2</sub> CEMS performance and excess SO<sub>2</sub> emissions were investigated for the period of 1st quarter of 2009 through the 2nd quarter of 2012. DEQ focused this investigation on the Zone A SRU burnouts following a review of all major SO<sub>2</sub> emitting facilities in the Billings/Laurel airshed that may have caused or contributed to the SO<sub>2</sub> National Ambient Air Quality Standard (NAAQS) exceedance at the Coburn Rd air monitoring station. The Zone A SRU has a two-tier set of allowable SO<sub>2</sub> limits. The initial or higher level of SO<sub>2</sub> limits were established under the Billings/Laurel SO<sub>2</sub> SIP Emission Control Plan in 1998. The later or lower tier SO<sub>2</sub> limits were established as a result of the federal CD and in accordance with the NSPS Subpart J and MACT Subpart UUU applicability, and, issued in MAQP #1821-10 on 10/16/03. The SO<sub>2</sub> excess emissions examined under this investigation did not exceed the older allowed SO<sub>2</sub> SIP limits (3-hour and 24-hour). However, the Zone A SRU was in excess of the (lower tier) allowed SO<sub>2</sub> emissions on a 1-hour, rolling 12-hour, and 24-hour basis. Excess SO<sub>2</sub> emissions occur due to two causes or reasons, namely SRU/TGTU shutdown and burnouts following the shutdown of the SRU and TGTU processing equipment. The Zone A SRU was in a burnout mode of operation when peak ambient SO<sub>2</sub> concentrations were measured at the Coburn Rd (September-October 2010) and Laurel (September 2011) air monitoring stations. CHS is required to follow the SRU

Preventative Maintenance and Operations Plan (PMOP) that is required under the federal CD. The PMOP must be revised annually. CHS is generally following this plan which requires upstream process units to shed sulfur in order to minimize excess SO<sub>2</sub> emissions at an SRU facility. However, the PMOP does not formally address burnout activities because the SRU is in a shutdown mode of operation and not receiving process acid gasses. While this activity may be an accepted industry practice, DEQ's concern is that the burnout activity may have potential to cause or contribute to a NAAQS SO<sub>2</sub> exceedance at either the Laurel or Coburn Rd ambient air monitoring stations. DEQ has requested compliance assistance from EPA's CD technical lead in reviewing excess SO<sub>2</sub> emissions from an SRU while in the burnout mode of operation. To date, EPA has yet to respond to DEQ's query regarding this matter. The Zone A SRU investigation also looked into a reporting errors in the monthly emission reports whereby the 24-hour SO<sub>2</sub> mass emission totals were incorrect due to summation errors associated with the incorrect set of 24 hour periods. CHS has been made aware of error and corrected the 1st quarter 2012 SO<sub>2</sub> emission report for the Zone A SRU.

On 4/21/08, the EPA issued final rules (Federal Register Vol. 73, No. 77) for a FIP that address identified deficiencies in the Billings/Laurel SO<sub>2</sub> SIP or Emission Control Plan. The FIP is a set of enforceable federal regulations that stand in the place of any deficient portions of the Montana SO<sub>2</sub> SIP, previously identified by the EPA, such as the lack of enforceable emission limits for flares. Final FIP rules call for continuous monitoring (total sulfur concentration and flow rate) of the flare gas header system for compliance with allowed SO<sub>2</sub> limits (e.g., 150 lbs SO<sub>2</sub>/3-hr period, 1200 lbs SO<sub>2</sub>/day and 219 tons per year) and a flare monitoring plan approved by EPA. The CHS refinery has reported the same annual rate of SO<sub>2</sub> emissions from the flare, 137 tons per year, for the past three consecutive years (2009 – 2011). To date, CHS has submitted two revisions of the required Flare Monitoring Plan to the EPA for approval. Upon final EPA approval, the refinery will have about one year to install the necessary flare monitoring equipment in order to demonstrate compliance with these applicable requirements of the FIP.

In general, the CHS refinery is in compliance with the terms and conditions of Operating Permit and the referenced applicable requirements as of the date of this report. DEQ made this determination based on information gathered at the time of the facility visit(s), the observations made during the facility visit(s), the review of the reports submitted by CHS during the review period, and the review of the compliance certifications submitted by CHS during the review period. A few areas of concern noted during the review period were excess emission periods associated with start-up/shutdown conditions, process upsets, and malfunction events. However, only those specific violations that have been identified in Section VI, Recent Compliance History, of this report were deemed to necessitate an enforcement response from DEQ. DEQ will continue to review the history of excess emissions reports, startup/shutdown conditions, process upsets, coke drum blowouts, SRU burnouts, and malfunction events in the future to determine if an enforcement response is warranted.

## SECTION II. SUMMARY OF EMISSION UNITS

### A. Facility Process Description

CHS is a petroleum refinery located in Laurel, Montana. The refining process distills crude oil using heat. This distillation separates the crude oil into its component parts. The refiner then cracks some of the heavier molecules by applying heat in the presence of a catalyst to make the reaction take place. These raw products are then treated in several ways to take out impurities. Finally, the proper liquids and additives are blended to create the desired product. The major processing equipment includes:

1. Atmospheric and vacuum crude distillation towers
2. Naphtha Hydrotreaters (NHT) (*previously Unifiners*)
3. Platformer (= Naphtha Reformer)
4. Fluidized Catalytic Cracking (FCC) Unit
5. Alkylation/Butamer/Merox/Saturate Units
6. Hydrodesulfurization (HDS) Unit and Hydrogen Plant
7. Four Sulfur Recovery Units (SRUs) with Tailgas Treatment Units (TGTUs)
8. Ultralow Sulfur Diesel Unit and Hydrogen Plant
9. Delayed Coker Unit
10. Benzene Reduction Unit
11. Transfer Facilities (Truck Product Loading, Railcar Product Loading)

### B. Emission Units and Pollution Control Device Identification

Emission Unit ID	Description	Pollution Control Device/Practice
EU001	Plant-wide and Multiple Emitting Unit Limitations	MAQP #1821-27 Limits, Billings/ Laurel SO <sub>2</sub> Stipulation, and MACT LDAR program, where applicable. CEMS on Refinery Fuel Gas Header(s).
EU002	#1 Crude Unit and Naphtha Splitter <ul style="list-style-type: none"> <li>#1 Crude Unit Preheater (CV-HTR-1)</li> <li>#1 Crude Unit Main Heater (CV-HTR-2)</li> <li>#1 Crude Unit Vacuum Heater (CV-HTR-4)</li> </ul>	LDAR, Billings/ Laurel SO <sub>2</sub> Stipulation
EU003	#2 Crude Unit <ul style="list-style-type: none"> <li>#2 Crude Unit Main Heater (2CV-HTR-1)</li> <li>#2 Crude Unit Vacuum Heater (2CV-HTR-2)</li> </ul>	LDAR, Billings/ Laurel SO <sub>2</sub> Stipulation
EU004	PDA Unit – <i>SHUTDOWN</i>	
EU005	Naphtha Hydrotreater Unit <ul style="list-style-type: none"> <li>NHT Charge Heater (H-8301)</li> <li>NHT Reboiler Heater #1 (H-8302)</li> <li>NHT Reboiler Heater #2 (H-8303)</li> <li>NHT Splitter Reboiler Heater (H-8304)</li> </ul>	LDAR, Billings/ Laurel SO <sub>2</sub> Stipulation
EU006	Middle Distillate Unifiner – <i>SHUT DOWN</i>	
EU007	Platformer Unit <ul style="list-style-type: none"> <li>Platformer Heater (P-HTR-1)</li> <li>Platformer Debutanizer Reboiler Heater (P-HTR-2)</li> <li>Platformer Splitter Reboiler (P-HTR-3)</li> <li>Platformer Recycle Compressor Turbine (C-4772)</li> <li>Benzene Reduction Unit Oily Water Sewer</li> </ul>	LDAR, Billings/ Laurel SO <sub>2</sub> Stipulation, Low NO <sub>x</sub> technology (Platformer Heater and Platformer Splitter Reboiler), NSPS Subpart QQQ

EU008	Fluid Catalytic Cracking (FCC) Unit <ul style="list-style-type: none"> <li>FCC Charge Heater (FCC-Heater-1)</li> <li>FCC Charge Heater (FCC-Heater-NEW)</li> <li>FCC Regenerator (FCC-VSSL-1)</li> </ul>	LDAR, SO <sub>2</sub> CEMS, Billings/ Laurel SO <sub>2</sub> Stipulation, Low NO <sub>x</sub> technology (FCC-Heater-NEW)
EU009	Alkylation/Butamer/Merox/Saturate Units <ul style="list-style-type: none"> <li>Alkylation Unit Hot Oil Belt Heater (ALKY-HTR-1)</li> <li>Miscellaneous Process Vent (Alkylation Unit Butamer Stabilizer Offgas)</li> </ul>	LDAR, Billings/ Laurel SO <sub>2</sub> Stipulation
EU010	Hydrodesulfurization Unit (Future Mild Hydrocracker) and Hydrogen Plant (100 Unit) <ul style="list-style-type: none"> <li>Reformer Heater (H-101)</li> <li>Reformer Heater (H-102)</li> <li>Reactor Charge Heater (H-201)</li> <li>Fractionator Feed Heater (H-202)</li> <li>Hydrogen Compressor Gas Engine (C-201B)</li> </ul>	LDAR, MAQP #1821-28 Limits, Low NO <sub>x</sub> Technology (on heaters), Billings/ Laurel SO <sub>2</sub> Stipulation
EU011	Zone D Sulfur Recovery Unit (SRU) and Tail Gas Treatment Unit (TGTU) <ul style="list-style-type: none"> <li>SRU Reheater (E-407)</li> <li>Incinerator (INC-401)</li> </ul>	MAQP #1821-28 Limits, Low NO <sub>x</sub> Technology, SO <sub>2</sub> CEMS, Billings/ Laurel SO <sub>2</sub> Stipulation
EU012	Zone A SRU and TGTU <ul style="list-style-type: none"> <li>#1 SRU Incinerator (SRU-AUX-4)</li> </ul>	SO <sub>2</sub> CEMS, Billings/ Laurel SO <sub>2</sub> Stipulation
EU013	Steam Generation Units <ul style="list-style-type: none"> <li>#1 Fuel Oil Heater (CV-HTR-9)</li> <li>#4 Boiler</li> <li>#5 Boiler</li> <li>#9 Boiler</li> <li>Boiler #10</li> <li>Boiler #11</li> <li>Boiler #12</li> </ul>	MAQP #1821-28 Limits Fuel Oil Flow Meters (#3, #4, #5 Boilers) LDAR and Low NO <sub>x</sub> Technology (Boilers #10, #11, and #12), Billings/ Laurel SO <sub>2</sub> Stipulation
EU014	Tank Farm (non-Wastewater): <ul style="list-style-type: none"> <li>MACT Group 1 Storage Vessels</li> <li>MACT Group 2 Storage Vessels</li> <li>Exempt – pressure vessels</li> <li>Exempt – not organic HAP</li> <li>Exempt – not refining</li> </ul>	Internal and External Floating Roofs, Fixed Roofs, LDAR (as applicable), Billings/ Laurel SO <sub>2</sub> Stipulation
EU015	Transfer Facilities <ul style="list-style-type: none"> <li>Asphalt Loading Heater #1</li> <li>Truck Product Loading Rack Vapor Combustion Unit (VCU)</li> <li>New Truck Loading Rack (VCU)</li> <li>Railcar Product Loading Rack VCU</li> </ul>	VCU on Light Product Truck Loading Racks and Railcar Loading Rack LDAR, Billings/ Laurel SO <sub>2</sub> Stipulation
EU016	Wastewater Treatment Units <ul style="list-style-type: none"> <li>Wastewater Treatment Unit (old)</li> <li>Wastewater Treatment Unit (new)</li> <li>Tanks: Tank 23, Tank 25, Tank 44, Tank 118, Tank 119, Tank 128, and Tank 129</li> <li>Desalter Wastewater Three-Phase Separator(s), API Separator(s), CPI Separator(s), Dissolved Air Flotation (DAF) Units</li> <li>New Wastewater Treatment Unit Vessels</li> </ul>	Enclosed conveyance and other wastewater controls for affected equipment per NSPS QQQ, NSPS Kb (as applicable)
EU017	Flare Systems <ul style="list-style-type: none"> <li>Refinery Flare (FL-7202)</li> <li>Zone E Coker Flare (FL-7201)</li> </ul>	Flare, Billings/ Laurel SO <sub>2</sub> Stipulation
EU018	RCRA Units	Restrictions on Land Tillage (HSPA permit)
EU019	Cooling Towers <ul style="list-style-type: none"> <li>Cooling Towers #1 - #3</li> <li>Cooling Tower #5</li> <li>Cooling Tower #6</li> </ul>	None

EU020	Saturate Gas Concentration Unit – <i>Eliminate EU, naphtha splitter consolidated with EU002</i>	
EU021	Ultra Low Sulfur Diesel (ULSD) (900 Unit) and Hydrogen Plant (1000 Unit) <ul style="list-style-type: none"> <li>• Reactor Charge Heater (H-901)</li> <li>• Fractionator Reboiler (H-902)</li> <li>• Reformer Heater (H-1001)</li> </ul>	LDAR
EU022	Delayed Coker Unit <ul style="list-style-type: none"> <li>• Coker Charge Heater (H-7501)</li> <li>• Coke Processing Operations</li> </ul>	LDAR, reasonable precautions for coke processing
EU023	Zone E SRU and TGTU	LDAR

### C. Categorically Insignificant Sources/Activities

Appendix A of Operating Permit #OP1821-11 lists insignificant emission units at the facility. The permittee is not required to update a list of insignificant emission units; therefore, the emission units and/or activities may change from those specified in Appendix A.

## **SECTION III. PERMIT CONDITIONS**

### **A. Emission Limits and Standards**

Emission limits and standards in the Title V permit were established from preconstruction permits, the Billings/Laurel SIP, NSPS requirements, NESHAP requirements, MACT requirements, and the USEPA Consent Decree entered February 2004. CHS currently has 27 active preconstruction permits. The following is a list of those permit numbers: #9-091868, #56-091569, #55-091569, #105-042970, #129-062270, #272-061171, #363-112971, #364-112971, #362-112971, #499-102372, #540-030773, #664-112073, #665-112073, #674-121973, #800-041675, #1111, #1161, #1176, #1175, #1168, #1169, #1170, #1173, #1174, #1317, #1552, #1821-28. Permits #14-110768, #1171, and #1172 were revoked.

### **B. Monitoring Requirements**

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods, required under applicable requirements, be contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance, does not require the permit to impose the same level of rigor for all emission units. Furthermore, it does not require extensive testing or monitoring to assure compliance with the applicable requirements for emission units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for an insignificant emissions unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo (**i.e., no monitoring**) will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emission units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

### **C. Test Methods and Procedures**

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, the permittee may elect to voluntarily conduct compliance testing to confirm its compliance status.

### **D. Recordkeeping Requirements**

The permittee is required to keep all records listed in the operating permit as a permanent business record for at least 5 years following the date of generation of the record.

### **E. Reporting Requirements**

Reporting requirements are included in the permit for each emission unit, and Section V of the operating permit, "General Conditions", explains the reporting requirements. However, the permittee is required to submit quarterly reports, semi-annual monitoring and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation.

To eliminate redundant reporting, a source may reference previously submitted reports (with at least the date and subject of the report) in the semi-annual and annual reports instead of resubmitting the information in quarterly, and/or other reports. However, a source must still certify continuous or intermittent compliance with each applicable requirement annually.

#### **F. Public Notice**

In accordance with ARM 17.8.1232, a public notice was published in the *Billings Gazette* newspaper on or before January 15, 2013. The Department provided a 30-day public comment period on the draft operating permit from January 15, 2013, to February 14, 2013. ARM 17.8.1232 requires the Department to keep a record of both comments and issues raised during the public participation process.

#### SECTION IV. NON-APPLICABLE REQUIREMENT ANALYSIS

CHS did not request a permit shield with this permit application. However, they did list non-applicable regulatory requirements and regulatory orders in the permit application and previous permit applications. The Department determined that the requirements identified in the permit application for the individual emission units are non-applicable. These requirements are contained in the permit in Section IV - Non-applicable Requirements.

The following table outlines those requirements that CHS identified as non-applicable in the permit application, but will not be included in the operating permit as non-applicable. The table includes both the applicable requirement and reason that the Department did not identify this requirement as non-applicable.

Applicable Requirement	Reason
ARM 17.8.324(2)	CHS noted that this does not apply as they do not have an oil-effluent water separator. However, this is a general applicable requirement that could apply in the future.
ARM 17.8.341	CHS noted that this does not apply. However, this is a general applicable requirement that could apply in the future.
ARM 17.8, SubChapter 8	CHS noted that this is not applicable. However, the Department can't shield from this requirement because this is major PSD source.

## **SECTION V. FUTURE PERMIT CONSIDERATIONS**

### **A. MACT Standards**

CHS is currently subject to 40 CFR 63, Subparts A, R, CC, UUU, and ZZZZ.

40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters (also referred to as the Boiler MACT): On May 16, 2011, EPA signed a stay delaying the effective dates for the final rule. The U.S. District Court for the DC Circuit vacated the stay on January 9, 2012. EPA issued a No Action Assurance Letter on February 7, 2012 letter indicating enforcement discretion would be used for violations of certain notification deadlines in the Major Source Boiler rule. EPA intends to proceed with the December 23, 2011 proposed rule and expect to finalize the new rules in April 2012.

The Department is not aware of any proposed or pending MACT standards, in addition to those already listed, that may be applicable.

### **B. NESHAP Standards**

The Department is not aware of any proposed or pending NESHAP standards, in addition to those already listed, that may be applicable.

### **C. NSPS Standards**

On September 12, 2012, EPA finalized the amendments, made some technical corrections and lifted the stay on 40 CFR 60, Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007. This rule became final and effective on November 13, 2012.

### **D. Risk Management Plan**

This facility does exceed minimum threshold quantities for any regulated substance listed in 40 CFR Part 68.115 for any facility process. Consequently, this facility is required to submit a Risk Management Plan.

If a facility has more than a threshold quantity of a regulated substance in a process, the facility must comply with 40 CFR Part 68 requirements no later than June 21, 1999; 3 years after the date on which a regulated substance is first listed under 40 CFR Part 68.130; or the date on which a regulated substance is first present in more than a threshold quantity in a process, whichever is later.

### **E. Compliance Assurance Monitoring (CAM) Plan**

An emitting unit located at a Title V facility that meets the following criteria listed in ARM 17.8.1503 is subject to Subchapter 15 and must develop a CAM Plan for that unit:

- The emitting unit is subject to an emission limitation or standard for the applicable regulated air pollutant (other than emission limits or standards proposed after November 15, 1990, since these regulations contain specific monitoring requirements);
- The emitting unit uses a control device to achieve compliance with such limit; and
- The emitting unit has potential pre-control device emission of the applicable regulated air pollutant that are greater than major source thresholds/

CHS does not currently have any emitting units that meet all the applicability criteria in ARM 17.8.1503, and is therefore not currently required to develop a CAM Plan.

## **F. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule**

On May 7, 2010, EPA published the “light duty vehicle rule” (Docket # EPA-HQ-OAR- 2009-0472, 75 FR 25324) controlling greenhouse gas (GHG) emissions from mobile sources, whereby GHG became a pollutant subject to regulation under the Federal and Montana Clean Air Act(s). On June 3, 2010, EPA promulgated the GHG “Tailoring Rule” (Docket # EPA-HQ-OAR-2009-0517, 75 FR 31514) which modified 40 CFR Parts 51, 52, 70, and 71 to specify which facilities are subject to GHG permitting requirements and when such facilities become subject to regulation for GHG under the PSD and Title V programs.

Under the Tailoring Rule, any PSD action (either a new major stationary source or a major modification at a major stationary source) taken for a pollutant or pollutants other than GHG that was not final prior to January 2, 2011, would be subject to PSD permitting requirements for GHG if the GHG increases associated with that action were at or above 75,000 TPY of carbon dioxide equivalent (CO<sub>2e</sub>) emissions. Similarly, if such action were taken, any resulting requirements would be subject to inclusion in the Title V Operating Permit. Starting on July 1, 2011, PSD permitting requirements would be triggered for modifications that were determined to be major under PSD based on GHG emissions alone, even if no other pollutant triggered a major modification. In addition, sources that exceed the 100,000 TPY CO<sub>2e</sub> threshold under Title V would be required to obtain a Title V Operating Permit if they were not already subject.

Based on information provided by CHS this permit action remained under the threshold. However, CHS may be subject to GHG permitting requirements in the future.